STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 6120

Tariff filing of Central Vermont Public Service)
Corporation requesting a 12.9% rate increase, to)
take effect July 27, 1998)

Docket No. 6460

In the Matter of Central Vermont Public Service)
Corporation requesting a 7.6% rate increase, to)
take effect December 24, 2000)

PREFILED DIRECT TESTIMONY OF BRUCE EDWARD BIEWALD ON BEHALF OF THE VERMONT DEPARTMENT OF PUBLIC SERVICE

Synapse Energy Economics, Inc.
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March 9, 2001

Summary: Mr. Biewald's testimony addresses used and useful policy issues, and their application to CVPS's purchase from Hydro Quebec, including projection of electricity market prices and the above market costs of the purchase.

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Prefiled Direct Testimony
of
Bruce Edward Biewald

1. Introduction

Q. Please state your name.

A. My name is Bruce Edward Biewald.

Q. State your name, occupation and business address.

A. My name is Bruce Edward Biewald. My address is Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, Massachusetts, 01239.

Q. Please describe your current employment.

A. I am President of Synapse Energy Economics, Inc., a consulting company specializing in economic and policy analysis of electricity restructuring, particularly issues of consumer protection, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q. What are your qualifications in the fields of electric utility regulation and energy policy?

A. I graduated from the Massachusetts Institute of Technology in 1981, where I studied energy use in buildings. I was employed for 15 years at the Tellus Institute, where I was Manager of the Electricity Program, responsible for studies on a broad range of electric system regulatory and policy issues. I have testified on energy issues in more than seventy regulatory proceedings in twenty-five states, two Canadian provinces, and before the Federal Energy Regulatory Commission. I have co-authored more than one hundred reports, including studies for the Electric Power Research Institute, the U.S. Department of Energy, the U.S. Environmental Protection Agency, the Office of Technology Assessment, the New England Governors' Conference, the New England Conference of Public Utility Commissioners, and the National Association of Regulatory Utility Commissioners. My papers have been published in the *Electricity Journal*, *Energy Journal*, *Energy Policy*, *Public Utilities Fortnightly* and numerous conference proceedings, and I have made presentations on the economic and environmental dimensions of energy throughout the U.S. and internationally. Recently I have been consulting for federal agencies, including the Department of Energy, the Department of Justice, the Environmental Protection Agency, and the Federal Trade Commission. In New England I represent the Union of Concerned Scientists on NEPOOL matters, and I am a member of the NEPOOL Participants Committee and the Environmental Planning Committee. My resume is provided here as Exhibit DPS-BEB-1.

Q. Have you previously testimony before the Vermont Public Service Board?

A. Yes. I testified on behalf of the Department of Public Service in the following dockets:

1) Docket No. 5854 on electric industry restructuring (hearings in July 1996).

2) Docket No. 5983 on GMP's rates (direct testimony in October 1997, rebuttal testimony in December 1997, and supplemental rebuttal testimony in January 1998).

3) Docket No. 6018 on CVPS's rates (direct testimony in February 1998).

4) Docket No. 6107 on GMP's rates (direct testimony in September 1998).

In addition, I have assisted the Department in other dockets including the prior CVPS case (Docket No. 6020) and the recently concluded GMP rate case (Docket No. 6107), both of which were settled.

2. Summary and Recommendations

Q. What is the purpose of your testimony in this case?

A. In this testimony I address used and useful policy issues, and their application to CVPS's purchase from Hydro Quebec. This includes a discussion of two projections of market prices, one by CVPS, and the other by Synapse Energy Economics. I then apply these electricity market prices in calculating the above market costs to CVPS of the contract over its remaining life.

Q. Please summarize your conclusions and recommendations.

A. My key conclusions are the following:

- CVPS's Hydro Quebec purchase is uneconomic. It is used, but not economically useful. I estimate the net economic losses over the remaining life of the contract to be $98 million in year 2001 present value.

- Using CVPS's forecast of electricity market prices, the net economic losses over the remaining life of the contract work out to $160 million, in year 2001 present value dollars.

- If the years 1999 and 2000 are added to analysis, then the magnitude of the above market costs is greater: $130 million with the Synapse market price forecast and $192 million with the CVPS market price forecast (in year 2001 present value dollars).

- Vermont's policy, articulated in a long series of decisions, is to share uneconomic costs between ratepayers and shareholders.

- The Board's policy of sharing uneconomic costs is a good one – it is fair and efficient.

- The purchase from Hydro Quebec should not be ascribed any environmental and risk benefits. There are various plausible scenarios for what might have happened if not for the transaction, but if there was an impact, it was most likely negative. That is, potential generating options in Quebec all involve considerable environmental impacts that would have at least offset the impacts of any avoided generation in New England, and the alternative transactions that might have occurred also have impacts that offset those of the Vermont purchase. Moreover, the purchase of a large fixed long-term capacity has its own risks, and is quite different from demand-side management measures (which do deserve a credit for their risk reduction benefits relative to conventional generating resources).

Based upon my review of regulatory decisions in Vermont and the facts in this case, I find that the Board can and should disallow a portion of the HQ purchase costs, because they are not used and useful. This would be appropriate even if there were no imprudence involved in the Company's commitment to the transaction. My recommendation in this case is that the Board apply its long-established used and useful policy in determining the appropriate rate treatment for CVPS's HQ purchase, and that any economic calculations done in applying that policy be based upon current electricity market price projections without adjustments for risk or environmental externalities. The degree of sharing of the excess costs between the Company and its customers is something over which the Board has considerable discretion.

My understanding is that Mr. Paul Chernick's testimony will address the damage caused by imprudence, and that Dr. William Steinhurst's testimony will present the Department's specific ratemaking recommendations for treatment of the costs of the HQ purchase with respect to used and useful, and imprudence.

3. Used and Useful Policy Issues

Q. Please explain what you mean by "used and useful" and how it relates to prudence in utility ratemaking.

A. If a regulated utility incurs costs imprudently, those costs should not be included in the rates that are charged to its customers. Of prudently incurred costs, only those found to be "used and useful" should be charged fully to customers. Costs of resources that are not used and useful should generally be shared between the Company's shareholders and customers. That is, only a portion of the excess costs would be included in regulated rates.

"Used and useful" means something more than "prudent" and more than simply "used." The useful portion of the phrase is most reasonably interpreted as "economic."

Q. Is this the "used and useful" policy generally applied in ratemaking treatment of uneconomic resources in Vermont?

A. Yes. The Board has developed a clear policy for the treatment of resources that are not "used and useful." It takes an economic view. That is, simply operating, or even being needed to meet capacity requirements is not sufficient for a resource to be deemed "used and useful." Rather, a resource must be economical. The Board has articulated its policy in several orders. The Board's order in Docket No. 5701/5724 quoted its prior order in Docket No. 5630 as follows:

> Ratemaking decisions in Vermont have been consistent with those federal and other state determinations. Our decision in Docket 5132 examined those precedents in detail.
>
> . . .
>
> In sum, six past precedents offer a consistent set of rules for calculating the rate effects of failed investments in major power plants:
>
> (i) if costs are imprudent, they cannot be included in rates;
>
> (ii) if costs exceed the degree to which projects are used and useful, only one-half of that excess is included in rates; and
>
> (iii) if an arms-length sale has occurred, the <u>net</u> benefits from that sale can be treated as a measure of the degree to which the project is used and useful. (Board Order in Docket No. 5701/5724, page 124, quoting Order in Docket 5630 et al., pages 51 and 52).

The Board also noted that in previous cases, when it found that portions of specific generation resources were not used and useful, then the losses were split evenly between shareholders and ratepayers. (Board Order in Docket No. 5701/5724, page 124.)

Q. The Board's language quoted above refers to "failed investments in major power plants." Should the policy apply to major purchased power contracts as well?

A. Yes, the Board's used and useful policy should apply to purchased power contracts such as CVPS's purchase from Hydro Quebec. While there are some differences between a purchased power commitment and a power plant investment, it is important that both be treated in a way that is roughly consistent in order to provide an overall policy that is coherent and efficient. Indeed, in the Board's February, 1998, decision in Docket No. 5983 it applied an economic used and useful standard in its rate treatment of GMP's purchase from Hydro Quebec. And again in its January 23, 2001 Order in Docket No. 6107, the Board reaffirmed its used and useful policy.

Q. In its 1994 Order dealing with CVPS's purchase from HQ, did the Board comment on expected developments in electricity markets and their implications for used and useful ratemaking?

A. Yes. In its October 31, 1994 Order in Docket Nos. 5701/5724, the Board did not accept the recommendations of the Department's witness, but the Board specifically stated that "...our ruling in the present matter should not be construed as a finding that a market-value test is fundamentally unacceptable." (Order at 126). The Board goes on to quote from the U. S. Supreme Court's decision in Duquesne Light Company v. Barasch, and then points out that "[a]s utility markets become more open and competitive, it may become increasingly possible and, in many cases, desirable to employ market-based tests to govern the utility's total return." (Order at 127).

Q. Do you agree with this point?

A. Yes. I believe that an economic used and useful test is appropriately applied in a fully regulated context. I also agree with the Board that increasing competition in utility markets makes the application of used and useful increasingly possible and desirable.

Q. Have conditions been changing in the state and regional electricity markets?

A. Yes. Since 1994, when the Board issued its decision in Docket 5701/5724, the New England wholesale electricity market has been restructured, shifting from cost-based to bid-based dispatch in May 1999. Nearly two-thirds of the electric generating capacity in the region has been sold by its regulated utility owners, revealing a market value for capacity of various types. Retail competition has been introduced in the other five New England states where some customers – primarily larger ones – have switched retail suppliers. The major federal milestones in deregulation include FERC's 1995 Open Access NOPR, FERC's 1996 Order No. 888, and FERC's 1999 Regional Transmission Organization NOPR.

In its May 13, 1999, Notice of Proposed Rulemaking on Regional Transmission

Organizations, FERC describes the "numerous significant developments" in the electric utility industry, which "have resulted in a considerably different industry landscape from the one faced at the time the Commission was developing Order No. 888, resulting in new regulatory and industry challenges." NOPR at 18. These include stresses on the transmission system, divestiture of generating capacity, mergers and acquisitions of utilities, an explosion of power marketing activity, and regulatory changes. NOPR at 18 to 21.

Robert Young's remarks at CVPS's last annual shareholders meeting on May 2, 2000 identified 1994 as the year that the "path to competition in Vermont began" and noted that "[s]ix years ago, we started a thorough examination of our company from top to bottom to cut costs and position CVPS for the Brave New World." Indeed, CVPS, Vermont's utility environment, and New England's electricity market have all look different today than they did in 1994.

Q. How do CVPS's rates compare with other companies?

A. CVPS's retail rates are high. The Edison Electric Institute (EEI) collects and publishes data on average revenue per kWh for 177 electric companies in the US. In Exhibit DPS-BEB-5, I have listed the top 20 and lowest 10 electric companies, with their average price for 1998 as reported by EEI. CVPS is number 10 in the Country, with an average price of 11.10 cents/kWh compared with the national average of $4.66/cents/kWh.

In New England, electricity prices are higher than in most other parts of the country. I have listed the 21 New England companies in Exhibit DPS-BEB-6, showing CVPS to be the fourth highest out of the 21 companies. The New England average price as reported by EEI is 10.08 cents/kWh. Vermont's other large electric company, GMP, is listed at 8.96 cents/kWh, putting it among the best of the New England companies (only three of the 21 companies listed have lower prices than GMP).

Q. In your view, is the Board's policy for sharing the costs of resources that are not used and useful fair and appropriate?

A. Yes. The Board's approach to ratemaking for uneconomic resources is fair and appropriate. Electric utility investors typically receive a return on their investment considerably above the return on low-risk investments such as treasury bills. The "risk premium" compensates investors for occasional circumstances in which investments fail economically. It is not the role of utility regulators to shield utilities from market risks. According to Bonbright:

> Regulation, it is said, is a substitute for competition. Hence, its objective should be to compel a regulated enterprise, despite its

> possession of partial or complete monopoly, to charge rates approximating those which it would charge if free from regulation but subject to competition. In short, regulation should not only be a substitute for competition, but a closely imitative substitute" (page 93, James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961).

Customers did not make the decisions to commit to the purchase from Hydro Quebec, nor are customers responsible for developments in electric generating technologies and fossil fuel markets that have rendered the purchase badly uneconomic. Under the circumstances, a sharing of the excess costs would be fair and appropriate. It is also economically efficient for management to bear some responsibility for poor economic outcomes.

4. Electricity Market Prices and Economics of CVPS's Purchase from HQ

Q. How does the cost of CVPS's purchase from Hydro Quebec compare with its value?

A. The cost of the purchase is much higher than its value. I estimate that the cost of CVPS's purchase will exceeds its value by $98 million over the remaining life of the contract (in year 2001 present value dollars, beginning with the year 2001).

Q. In developing this estimate, what did you project for the market price of electricity?

A. My projection of electricity market prices is presented in Exhibit DPS-BEB-3. It is based upon electricity futures market prices for the next two years, and then is trended to an "equilibrium" price based upon the cost of owning and operating a natural gas combined cycle plant. The projected market price is $60.4/MWh in 2001 declining to $39.5/Mwh in 2007, after which it increases gradually. (These prices are in year 2000 constant dollars, including capacity, for a 75% capacity factor.)

Q. How does this compare with the estimates in your previous testimony in Vermont that were used by the Board's in its Order in Docket No. 5983?

A. The estimated excess cost of the purchase is between the "mid" and "high" case estimates from my February 1998 testimony in Docket No. 6018. The economic losses are lower than estimated three years ago, due to higher near term electricity market prices and a shorter remaining contract duration.

Q. Is your economic analysis dependent upon an assumption that the alternative to CVPS's purchase from Hydro Quebec is spot market purchases?

A No. In this and in previous testimony I compare the costs of the purchase from Hydro Quebec with the market prices for electricity in New England. Those market prices are routinely forecast in a manner that includes capacity and energy. Year to year prices will fluctuate, but because the forecasts (and the actual market prices) are in large part determined by the assumed cost of market entry, there is a strong feedback mechanism to "correct" prices that are too high or too low relative to the cost of building and operating a new power plant.

The approach that I take in forecasting market prices is quite standard. It is the same basic approach used by CVPS in its projection of market prices provided in response to data requests in this case.

Q. Has CVPS forecast the above market costs associated with its purchase from Hydro Quebec?

A. No, at least not a public forecast. In Response to Question 19 of the Department's Second Set of Data Requests, CVPS explains that it did a "retrospective analysis of the lock-in decision" in 1994, and that since that time it has conducted "some partial and incomplete analyses, which compare the costs of the HQ contract to various alternatives" but that these "were conducted in preparation for litigation and hence are confidential." However, CVPS did provide a forecast of electricity market prices, and that forecast implies an amount of economic losses for the purchase.

Q. What is CVPS's latest projection of electricity market prices, and what does it imply for the economic losses from the HQ purchase?

A. CVPS provided its projection of market prices in response to Question 7 of the Department's Second Set of Data Requests. CVPS's market price forecast is a bit lower that the Synapse forecast, primarily because CVPS is more optimistic than I am about the costs and performance of new gas combined cycle plants. The Company's lower market price projection implies greater economic losses from the HQ contract. I have presented CVPS's market price forecast in Exhibit DPS-BEB-2, and have applied it to the projected costs of the Company's purchase from Hydro Quebec in Exhibit DPS-BEB-4. In applying the forecast, I have made an upward adjustment to CVPS's prices to account for the capacity factor of the HQ purchase. The resulting estimate of economic losses is $160 million (in year 2001 present value dollars, beginning with the year 2001).

Q. If the years 1999 and 2000 were incorporated into the analysis, how would they change the amount of above market costs for CVPS's purchase from Hydro Quebec?

A. The total amount of above market costs would increase with the addition of those two years. Based upon market price data from ISO New England, I estimate that my figure for above market costs for the contract of $98 million beginning with 2001 would increase to $130 million for an analysis beginning with 1999. For the case with CVPS's market price forecast the above market costs would increase from $160 million (beginning with 2001) to $192 million (beginning with 1999). All of these figures are expressed in year 2001 present value dollars.

5. Environmental Impacts and Risk Implications of the Purchase

Q. Should the purchase from Hydro Quebec be ascribed credit for environmental benefits and risk reduction?

A. No.

Q. Why should there be no environmental credit ascribed to the Hydro Quebec purchase in applying used and useful ratemaking?

A. In most outcomes that I can contemplate, if CVPS had not made this purchase, the change in terms of environmental impacts would have been nil. In the few situations where I can imagine some net environmental impact, the impacts in the absence of the purchase would have been worse. The possible resource changes that I can think of that might possibly be attributed to Vermont's purchase from Hydro Quebec are: (1) incremental construction of hydro capacity in James Bay; (2) decreased potential sales from Quebec to Ontario; (3) displacement of other possible sales from Quebec to the Northeast US; (4) accelerated development of new gas generation in Quebec; and (5) incremental operation of existing oil-fired plant in Quebec.

In the first case, it must be recognized that the production of electricity in James Bay by Hydro Quebec has its own significant and undesirable environmental consequences. The environmental costs from large scale hydro generation include significant flooding of pristine wilderness and resulting methane and carbon dioxide emissions, ecological impacts resulting from downstream flow modifications, and cultural impacts on the Native people that occupy the region.

In the second case, that if not for Vermont's purchase then Quebec would have sold the power to Ontario – there could have been considerable environmental benefits depending upon Ontario Hydro's actions. Ontario's generating mix includes some very highly emitting coal generation. If that coal generation were backed down as a result of an Ontario purchase from Quebec, then the environmental effect of additional electricity imports in Ontario would likely have been beneficial compared with the impact of a sale to New England, where oil and gas generation would have been displaced. If instead Ontario decreased its oil generation then the effect likely would have been comparable to the effect of a sale to New England.

The third case is an interesting one. If the effect of Vermont's purchase from Quebec was to displace other possible sales from Quebec into New England, then the net environmental effect is exactly zero.

The fourth case was put forward by one of GMP's witnesses in Docket No. 6107 where he testified that "Certainly, if the HQ/VJO Contract had been canceled, HQ could have (and did) pursue NUG contract buyouts or deferrals more aggressively." (Oliver pfrt. at 69) If this conjecture were true, then the environmental benefits attributable to the purchase would be the difference between the generation that would have taken place in New England (mainly from new gas-fired NUGs in New England) and the generation deferred in Quebec. If one takes the Quebec NUGs to be gas-fired capacity then this would work out to approximately zero (or negative to the extent that NUG is Quebec would be subject to looser environmental regulations than NUGs in New England).

Finally, the fifth case, with additional oil-fired generation in Quebec, would result in substantially greater environmental impacts. It is possible that the sale of energy from Quebec to Vermont is resulting in the operation of Hydro Quebec's Tracy Station. Tracy is an older 600 MW oil-steam plant that was built in the 1960s and was mothballed in the 1980s only to be rehabilitated several years later. It is particularly likely that in the near term the effect of the sale to Vermont is resulting in increased generation from this plant. To the extent that this is occurring, the environmental impacts of the transaction will be negative, since Tracy's emission rates are higher than the emission rates of marginal New England generation, and much higher than the emission rates of new combined-cycle generation. For example, SO_2 emissions from Tracy are reported at 17 lbs./MWh, while the SO_2 emissions from the marginal generation in NEPOOL are about 6 lbs./MWh, and the SO_2 emissions from a new gas fired plant are effectively zero.

Q. Has Tracy been running recently, and why would you say that it is the marginal source of generation in Quebec?

A. Yes, after operating at very low capacity factors in the years from 1993 to 1997, Tracy began generating in significant quantities. In 1998 and 1999 Tracy generated about 1.5 TWh and 1.0 TWh respectively. For comparison, CVPS's annual purchases from Hydro Quebec are less than 1 TWh.

It is reasonable to believe that Tracy is the marginal source of generation in Quebec, since the rest of the Hydro Quebec system is almost entirely hydroelectric and to a lesser extent nuclear. For hydro and nuclear generation, there are large fixed costs, but low short run variable costs of operation, so these facilities will be dispatched before an oil-fired generator. The Hydro Quebec system has so much storage capability that it is "energy limited." If less energy were exported from the Province then of the plants that are actually operating, the plant with the highest operating costs would be the plant that would be backed off. In Quebec in recent years, this plant has been Tracy.

Q. Why should no risk credit be ascribed to the Hydro Quebec purchase?

A. Because the purchase itself has considerable risks relative to other resource options. In assessing the risks of different resource options, it is well recognized that options involving a firm commitment to a high fixed cost stream such as the purchase from Hydro Quebec are undesirable from a risk perspective. Studies of the "option value" of resource commitments generally find that deferring a decision to lock in to a particular resource has significant real value. The value of deferring irreversible decisions is central to this concept. One paper by Pindyck paper which states:

> "When a firm makes an irreversible investment expenditure, it exercises, or "kills," its option to invest. It gives up the possibility of waiting for new information to arrive that might affect the desirability or timing of the expenditure; it cannot disinvest should market conditions change adversely. This lost option value is an opportunity cost that must be included as part of the cost of the investment." And "Recent studies have shown that this opportunity cost of investing can be large, and investment rules that ignore it can be grossly in error." (Robert Pindyck, "Irreversibility, Uncertainty, and Investment," Journal of Economic Literature, September 1991, page 1112)

It is a common sense notion that maintaining flexibility has value. Decision tree analysis techniques can be used to quantify that value, given estimated probabilities for various outcomes. In situations such as electric system resource planning, in which additional information is revealed over time, the value of deferring a decision can be particularly large.

I believe that the Board was quite correct in its decision that because the HQ contract does not have the beneficial risk-reducing attributes demand-side management resources ("flexibility, short lead time, availability in small increments, and ability to grow with load") that it would be "inappropriate to apply the same risk adjustment to the

HQ-VJO Contract that this Board does to energy efficiency resources." Docket No. 6107, Order of 1/23/01 at 47.

Q. Does this conclude your testimony?

A. Yes.

CVPS's Forecast of New England Electricity Market Prices

Central Vermont Public Service Company produced both short and long term market price forecasts. The short term forecast was based on a mix of natural gas and oil prices used to project electricity prices through 2003. The long term forecast was based on full equivalent cost of a new gas combined cycle plant.

The short term forecast was contained in the file "ECP_Forecast_Filing.xls" (values represented in shaded area).

The long term forecast was contained in the file "forefo.wk4" and is based on full equivalent costs of a new gas combined cycle unit running at a 90% capacity factor. Prices are in constant year 2000 dollars per MWh. The natural gas price forecast was from the file "Forecast_DPS_2000.xls" containing a forecast prepared by a consultant to the Department of Public Service.

The results below were provided in response to the Question 7 of the DPS's 2nd Set of Data Requests and have been deflated using CVPS's inflation rate of 2.6% to year 2000 constant dollars.

Table DPS-BEB-2-1
CVPS Market Price Forecast
(Including Capacity Value at a 100% Capacity Factor)

Year	2000$/MWh
2001	**48.89**
2002	**42.86**
2003	**39.17**
2004	**33.63**
2005	**33.69**
2006	**33.76**
2007	**33.83**
2008	**33.90**
2009	**33.99**
2010	**34.17**
2011	**34.35**
2012	**34.55**
2013	**34.76**
2014	**34.98**
2015	**35.24**
2016	**35.52**
2017	**35.80**
2018	**36.09**
2019	**36.40**

Synapse Energy Economics Forecast of New England Electricity Market Prices

The Synapse market price forecast consists of three pieces:

1. Short term prices through 2003 are based on *NatSource* electricity futures. These prices are from February 23, 2001 and are presented in Table DPS-BEB-3-1 below.

2. From 2004 onward, electricity prices based on full cost recovery for a new gas combined cycle plant. Combined cycle assumptions are presented in Table DPS-BEB-3-3 below.
   b. Intermediate term 2004-2006 gas prices are based on a linear interpolation from the NYMEX Henry Hub natural gas futures price in 2002 to the DPS forecast price in 2007 (transportation adders to Boston City Gate were incorporated).
   c. Long term natural gas prices from 2007 onward are taken from DPS Forecast 2000A.

For the short term, we used the NEPOOL electric futures from *NatSource*. Since the data has incomplete coverage as shown below, we had to fill in off-peak and ICAP prices using the peak[1] prices as a guide.

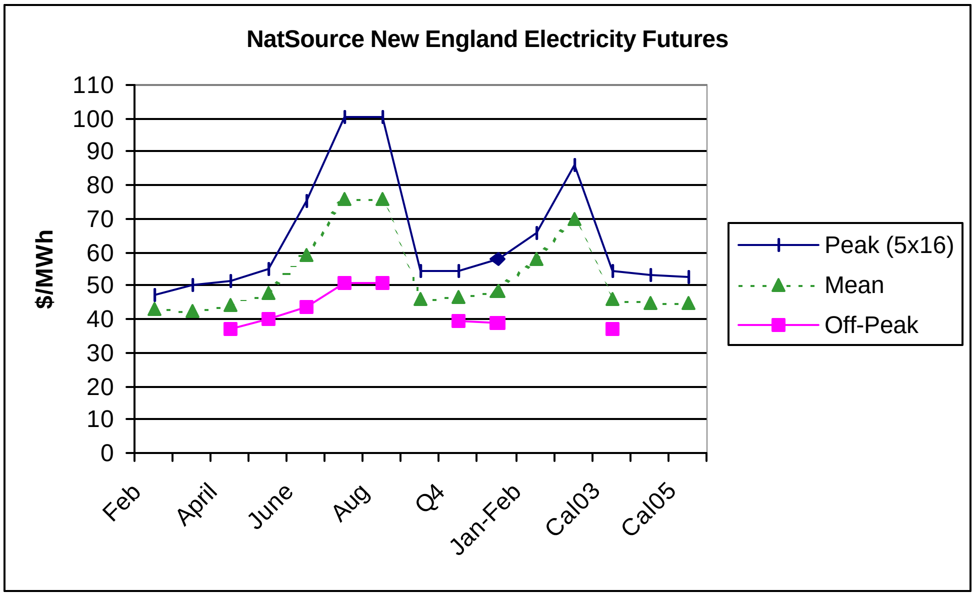
Table DPS-BEB-3-1

NatSource Futures - 2/23/01

		Energy		
Period	Peak	Off-Peak	Average	ICAP
	$/MWh	$/MWh	$/MWh	$/kW-mo
Feb	47.0			
March	50.5			2.6
April	51.5	37.0	44.3	
May	55.3	40.0	47.6	
June	75.4	43.5	59.4	
Jul	100.5	51.0	75.8	3.1
Aug	100.5	51.0	75.8	3.1
Sep	54.1			
Q4	54.3	39.5	46.9	3.0
Cal02	57.8	38.9	48.3	2.8
Jan-Feb	66.0			
Jul-Aug	86.0			
Cal03	54.5	37.0	45.8	
Cal04	53.0			
Cal05	52.8			

[1] Peak period refers to the "5x16" (weekday) category. Off-peak is the "5x8,2x24" (evening and weekend) category.

Figure DPS-BEB-3-1



After including ICAP costs and adjusting for load factor and inflation we arrived at the following price forecast:

Table DPS-BEB-3-2

Market Price for a 75% Load Factor

Year	Year 2000 Constant $/MWh
2001[2]	60.4
2002	53.5
2003	49.6

For the intermediate and long term we use the full cost of a gas combined cycle plant as the basis for determing the equivalent market price. The combined cycle plant cost and performance inputs are summarized in Table DPS-BEB-3-3, below. These are the same values as developed for our 2000 study for the Vermont Department of Taxes. That report, entitled “Valuation of Hydroelectric Generating Facilities on the Connecticut and Deerfield Rivers in Vermont” is available on www.synapse-energy.com in the “Publications” section.

[2] Includes actual ISO NE prices for Jan & Feb of 2001.

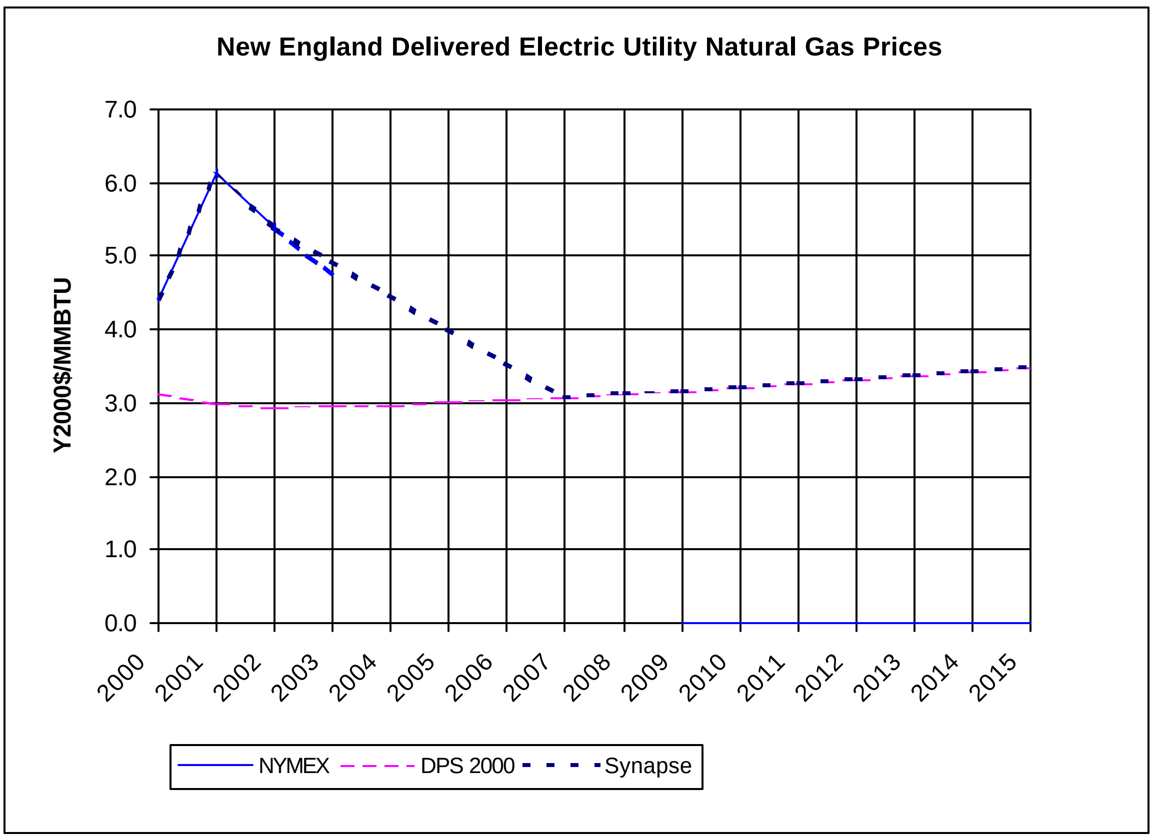
Table DPS-BEB-3-3

New Gas Combined Cycle Plants

Base Year $	1998
Capital Cost ($/kW)	650
Heat rate (Btu/kWh)	7100
Fixed O&M ($/kW-yr.)	32.64
Variable O&M ($/MWh)	1.25
NOX emission rate (lb/MMBtu)	0.04
Capital Recovery Period	30
Real Capital Recovery Factor	10.67%

For the intermediate term natural gas price forecast we took the NYMEX Henry Hub natural gas futures from 2002 and then interpolated to the DPS price for 2007 (transportation adders to Boston City Gate were incorporated).

Figure DPS-BEB-3-2



The higher of these two gas prices was then used to generate the equivalent NG CC electricity cost. Table DPS-BEB-3-4 below summarize the results for this Synapse market price forecast.

Table DPS-BEB-3-4
Synapse Market Price Forecast
(Including Capacity Value at 75% Capacity Factor)

Year	Synapse (2000$/MWh)	Source
2001	60.4	*NatSource* Electricity Futures
2002	53.5	
2003	49.6	
2004	49.3	Gas CC, with fuel price from linear interpolation between NYMEX Futures (2002) and VT DPS gas forecast (2007)
2005	46.0	
2006	42.8	
2007	39.5	Gas CC, with fuel price from VT DPS 2000 natural gas forecast
2008	39.7	
2009	40.0	
2010	40.4	
2011	40.7	
2012	41.1	
2013	41.5	
2014	41.9	
2015	42.3	

Quantification of the Excess Costs of CVPS's Hydro Quebec Purchase

The above market costs of CVPS's purchase from Hydro Quebec are calculated by taking the difference between the projected contract payments and the value of the power, at a projected market price. Here, we apply two different projections of market price, one by CVPS the other by Synapse Energy Economics.

The annual Hydro Quebec contract costs are extracted directly from the "HQ_FORC.WK4" file provided by CVPS in response to Question 7 of the DPS's 2nd set of Data Requests. The results are summarized below, with the numbers in bold representing directly copied data. CVPS's projected general inflation rate of 2.6% was applied to deflate the nominal dollar figures to obtain the constant dollar column at the right side of the table. The costs are presented in Table DPS-BEB-4-1 below.

Table DPS-BEB-4-1

	HQ Contract Costs							
		- From "HQ_FORC.xls"						
	Generation	Energy Cost	Energy Price	Capacity	Capacity Cost	Capacity Price	Total Cost	Total Cost
Year	MWh	(Nominal $)	(Nominal $/MWh)	(MW)	(Nominal $)	(Nominal $/kW)	(Nominal 1000$)	(Constant 1000$)
2001	**937,984**	**24,667,902**	26.3	**142.8**	**35,358,310**	247.6	60,026	58,505
2002	**937,984**	**25,284,600**	27.0	**142.8**	**35,358,310**	247.6	60,643	57,608
2003	**937,984**	**25,916,715**	27.6	**142.8**	**35,358,310**	247.6	61,257	56,734
2004	**937,984**	**26,564,633**	28.3	**142.8**	**35,358,310**	247.6	61,923	55,881
2005	**937,984**	**27,228,749**	29.0	**142.8**	**35,358,310**	247.6	62,587	55,049
2006	**937,984**	**27,909,467**	29.8	**142.8**	**35,358,310**	247.6	63,268	54,237
2007	**937,984**	**28,607,204**	30.5	**142.8**	**35,358,310**	247.6	63,966	53,446
2008	**937,984**	**29,322,384**	31.3	**142.8**	**35,358,310**	247.6	64,681	52,674
2009	**937,984**	**30,055,444**	32.0	**142.8**	**35,358,310**	247.6	65,414	51,921
2010	**937,984**	**30,806,830**	32.8	**142.8**	**35,358,310**	247.6	66,165	51,187
2011	**937,984**	**31,577,000**	33.7	**142.8**	**35,358,310**	247.6	66,935	50,470
2012	**937,984**	**31,339,529**	33.4	**155.3**	**35,358,460**	227.6	66,698	49,017
2013	**762,204**	**26,958,474**	35.4	**116.1**	**29,054,884**	250.3	56,013	40,121
2014	**762,204**	**27,632,436**	36.3	**116.1**	**29,054,884**	250.3	56,687	39,575
2015	**762,204**	**24,481,170**	32.1	**116.1**	**29,054,884**	250.3	53,536	36,428

Comparing the Costs of the HQ Contract with Synapse and CVPS Market price Forecasts

Table DPS-BEB-4-2 below compares the annual electricity costs of the HQ Contract to Synapse and CVPS[1] market price assumptions. Figure DPS-BEB-4-1 on the following page illustrates the table below.

Table DPS-BEB-4-2

Hydro Quebec Purchase Costs and Value

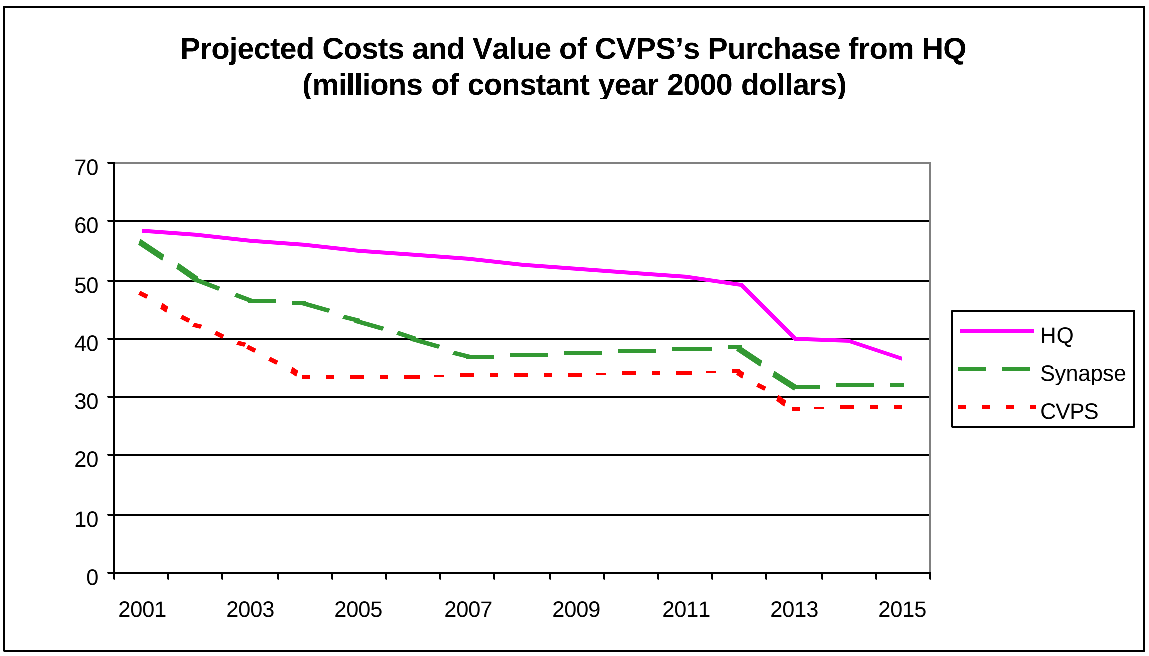
(Annual costs are in thousands of year 2000 constant dollars)

Year	HQ Contract Costs	Value With Synapse Market Price Forecast	Value With CVPS Market Price Forecast
2001	58,505	56,658	47,891
2002	57,608	50,200	42,196
2003	56,734	46,542	38,696
2004	55,881	46,248	33,498
2005	55,049	43,174	33,554
2006	54,237	40,101	33,615
2007	53,446	37,027	33,681
2008	52,674	37,274	33,752
2009	51,921	37,528	33,834
2010	51,187	37,868	33,999
2011	50,470	38,218	34,174
2012	49,017	38,572	34,361
2013	40,121	31,635	28,081
2014	39,575	31,932	28,245
2015	36,428	32,264	28,446
Cumulative Present Value (in thousands of 2001 PV dollars)	501,956	403,684	341,891
Above Market Costs (in millions of 2001 PV dollars)	NA	98	160

[1] In creating Table DPS-BEB-4-2 "CVPS" column the CVPS market price forecast presented in Exhibit DPS-BEB-2 was adjusted upward slightly to account for the 75% capacity factor of the HQ Contract.

The present value totals are calculated using a 10 percent discount rate (7.4 percent real). The "above market costs" projected to be $98 million and $160 million with the Synapse and CVPS forecasts, respectively, are the differences between the costs of the contract and its projected value.

Figure DPS-BEB-4-1



Average Electricity Prices for 177 Electric Companies in the United States: Highest 20 and Lowest 10 Companies (Data for 1998 from EEI's "Typical Bills and Average Rates Report: Winter 1999")

Rank	Company	Average Price (cents/ kWh)
1	Maui Electric Company (Lanai)	18.33
2	Maui Electric Company (Molokai)	17.76
3	Hawaii Electric Light Company	16.97
4	Consolidated Edison Company of New York	13.79
5	Maui Electric Company (Maui)	12.99
6	Public Service Company of New Hampshire	12.18
7	United Illuminating Company	11.58
8	Commonwealth Electric Company	11.30
9	Central Vermont Public Service Corporation	11.10
10	Newport Electric Corporation	10.79
11	GPU Energy	10.56
12	Boston Edison Company	10.50
13	Maine Public Service Company	10.31
14	Bangor Hydro-Electric Company	10.29
15	Hawaiian Electric Company	10.26
16	Connecticut Light & Power Company	10.18
17	Exeter & Hampton Electric Company	9.89
18	Fitchburg Gas & Electric Light Company	9.87
19	Rockland Electric Company	9.83
20	Central Maine Power Company	9.75
	. . .	
168	AmerenUE	4.05
169	Wisconsin Public Service Corporation	4.02
170	AEP (Kentucky Power Rate Area)	4.00
171	Kentucky Utilities Company	4.00
172	Monongahela Power Company	3.98
173	Idaho Power Company	3.84
174	PacifiCorp	3.79
175	PacifiCorp	3.71
176	Idaho Power Company	3.59
177	Wisconsin Electric Power Company	3.43
	United States Average for 177 Companies	4.66

Average Electricity Prices for 21 Electric Companies in New England
(Data for 1998 from EEI's "Typical Bills and Average Rates Report: Winter 1999")

Rank	Company	Average Price (cents/ kWh)
1	Public Service Company of New Hampshire	12.18
2	United Illuminating Company	11.58
3	Commonwealth Electric Company	11.30
4	Central Vermont Public Service Corporation	11.10
5	Newport Electric Corporation	10.79
6	Boston Edison Company	10.50
7	Maine Public Service Company	10.31
8	Bangor Hydro-Electric Company	10.29
9	Connecticut Light & Power Company	10.18
10	Exeter & Hampton Electric Company	9.89
11	Fitchburg Gas & Electric Light Company	9.87
12	Central Maine Power Company	9.75
13	Concord Electric Company	9.70
14	Narragansett Electric Company	9.67
15	Eastern Edison Company	9.49
16	Western Massachusetts Electric Company	9.26
17	Blackstone Valley Electric Company	9.19
18	Green Mountain Power Company	8.96
19	Granite State Electric Company	8.71
20	Massachusetts Electric Company	8.50
21	Cambridge Electric Company	8.11
	New England Average for 21 Companies	10.08